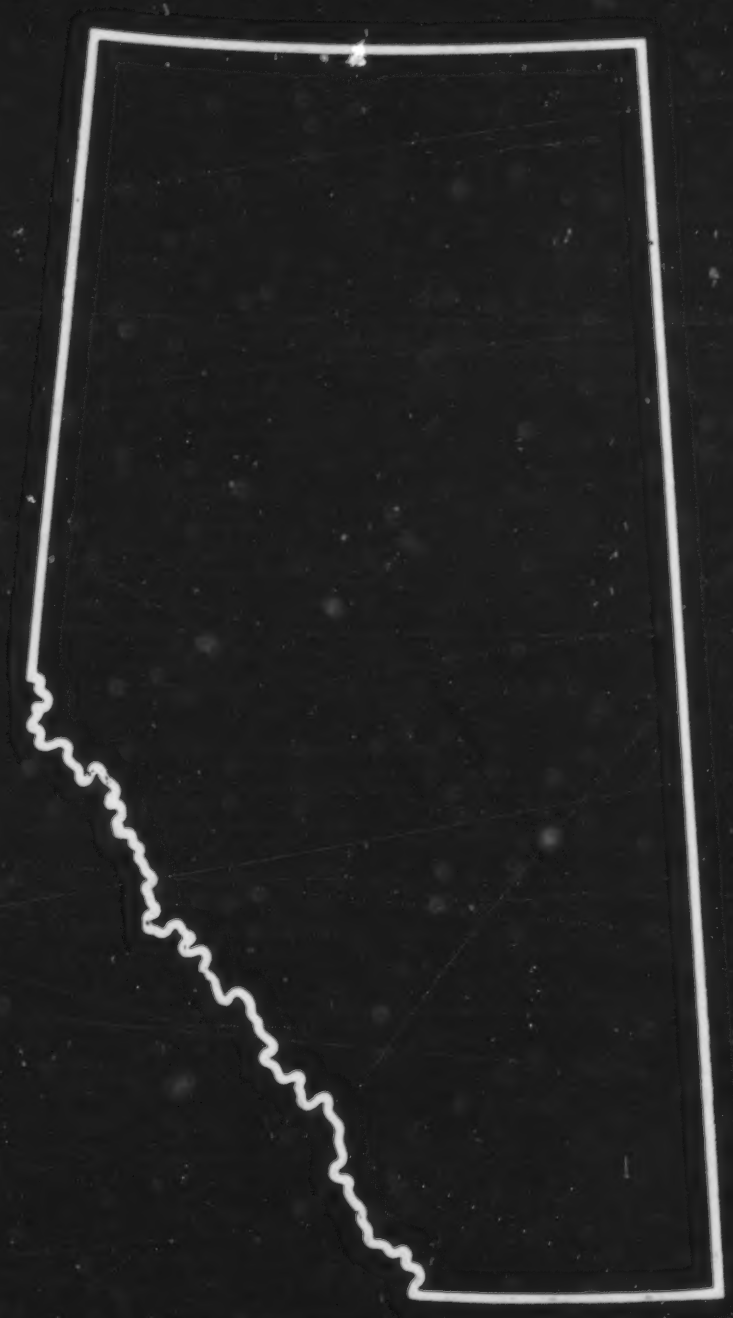

Alberta PETROLEUM MARKETING COMMISSION

1989 ANNUAL REPORT

Alberta PETROLEUM MARKETING COMMISSION

1900 - 250 Sixth Avenue S.W., Calgary, Alberta, Canada T2P 3H7 Telephone (403) 297-5500 Fax (403) 263-8144

June 7, 1990

The Honorable Rick Orman
Minister of Energy
Government of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B6

Dear Sir:

In accordance with the provisions of the Petroleum Marketing Act, the Natural Gas Pricing Agreement Act and the Take-or-pay Costs Sharing Act, the Alberta Petroleum Marketing Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1989. I have the pleasure to submit the 1989 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,

D.A. Lucas
Chairman

90-06399/1

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The Homestead, an original oil painting by Georgia Jarvis, captures the history, abundance and beauty of Alberta's Eastern Slopes.

Ms. Jarvis lives in the Springbank area west of Calgary, Alberta with her husband Warren and their sons David and Jim.

MESSAGE FROM THE CHAIRMAN

World crude oil prices both strengthened and stabilized during 1989, reflecting OPEC production restraint early in the year and modest growth in demand. The North American market was further bolstered by continuing declines in indigenous production which resulted in premium prices for Alberta crude. As a result of a reduction in Alberta supply, both Interprovincial Pipe Line Company and Trans Mountain Pipe Line Company Ltd. shelved plans for system expansions.

Alberta crude production was particularly affected during 1989 by lower drilling levels resulting from a significant amount of merger and acquisition activity in the oil and gas industry, together with a shift in exploration interest towards natural gas.

Over the year, the APMC faced ongoing marketing challenges in the form of reduced royalty volumes, a changing crude slate, increased transportation costs and a strong Canadian dollar. The APMC continued to optimize revenues by adapting its sales strategies and diversifying markets.

Amid evidence of strengthening North American natural gas markets overall, Alberta's producers faced persistent competitive pressures, particularly in the ex-Alberta domestic market. Progress was made towards realizing the new pipeline capacity needed to improve access to the growing United States market, with producers voting to approve the Iroquois project proposed to serve the northeast United States. Plans for new pipelines and expansions into the California market also were initiated.

In the regulatory arena, the APMC continued to focus on reinforcing the need to rely on market forces to determine where crude oil and natural gas should be sold, to whom and for what prices and under what conditions. In the coming year, the APMC will be devoting considerable resources towards promoting timely and economic pipeline expansions, and applying fair and reasonable tolling methods.

MARKET OVERVIEW

PETROLEUM MARKETS

Launched by OPEC production restraint and demand growth and buoyed throughout the year by special factors, world crude oil prices recovered substantially during 1989. As measured by West Texas Intermediate (WTI), 1989 crude oil prices averaged US$19.59 per barrel, up $3.62 over 1988.

In 1989, non-Communist consumption grew by approximately one million barrels per day. OPEC production cutbacks of 2.5 million barrels per day during the first half of the year helped underpin market confidence. As a consequence, all major international crude oil prices strengthened. WTI led the recovery, rallying from an average of US$13.98 per barrel in November 1988 to US$20.94 in April 1989.

Over the balance of the year, special factors helped sustain crude oil markets. A series of accidents curtailed production in the United Kingdom's sector of the North Sea, the Valdez tanker incident resulted in restricted shipping operations, and weather in the fourth quarter was abnormally cold. In addition, United States output continued to decline. The resulting decrease of approximately 600 thousand barrels per day in oil output from member countries of the Organization for Economic Co-operation and Development, combined with healthy economic growth and increased oil consumption in the Pacific Rim, enabled OPEC to increase significantly its market share over the course of the year.

During the year, OPEC's strategy shifted from one of pursuing market share at the expense of price, towards one of providing market requirements at prevailing prices. As a result, prices were much less volatile during the year and the cartel's production averaged 21.7 million barrels per day, up 2.0 million barrels from 1988.

Throughout 1989, OPEC output steadily increased, rising from 20.0 million barrels per day in January to 24.0 million in December, the highest level since early 1981. These gains were accompanied by increases in OPEC's official quota, from 18.5 million barrels per day for the first half of 1989 to 20.5 million for the fourth quarter. During 1989, the major OPEC overproducers were Kuwait, at a reported average 520 thousand barrels per day over quota and the United Arab Emirates, estimated at 850 thousand barrels per day over quota. At its November meeting, OPEC raised its overall quota to 22.0 million barrels per day for the first half of 1990. Of this amount, Kuwait received a disproportional increase, while the United Arab Emirates received no increase.

In addition to growing OPEC production levels, the past year demonstrated a renewed concern with environmental issues worldwide, fuelled by several major tanker accidents and increasing awareness of the quality of the environment. These concerns are triggering government policies aimed at reducing pollution and improving environmental protection. This focus likely will intensify in the future and could cause profound and far-reaching changes in the oil industry. These changes could include the reallocation of investments to less environmentally-sensitive areas, the development of alternative cleaner transportation fuels, intensified efforts towards increasing energy efficiency and the construction of safer tankers.

United States

In 1989, total United States crude oil production declined by the largest amount ever recorded for one year. This reflected an accelerated decline in output from the Lower 48, combined with a reversal in the upward trend in Alaska's output witnessed over the past decade. During 1989, Lower 48 output fell to 5.7 million barrels per day, a decline of seven percent. Alaskan production also decreased seven percent to 1.9 million barrels per day.

Although crude oil prices were stronger in 1989, the United States oil industry did not commit to developments in domestic plays, opting instead for better prospects in other countries. Accordingly, refineries relied on increased imports to meet their requirements. These imports grew to 5.8 million barrels per day, an increase of 730 thousand barrels per day over 1988.

While imports continued to rise, United States consumption was flat during 1989, in contrast to growth of three percent during each of the previous three years. Most notably, gasoline demand was inhibited by higher prices early in the year and slower economic growth.

Canada

Canadian production of crude oil dropped three percent in 1989 to 266 thousand cubic metres (1.7 million barrels) per day. Alberta production also declined three percent, reflecting lower production from established wells, very low drilling activity and deferrals of several heavy oil projects. The latter two factors in part reflected oil price uncertainty and weaker prices in 1988, when corporate budgets for 1989 were established.

In addition, a shift was apparent in exploration intent, from crude oil towards natural gas. There was also a shift by larger companies to purchase reserves rather than invest in exploration. The composition of total Alberta output shifted in favour of non-conventional crudes (Figure 1). A three percent increase in bitumen, pentanes plus and synthetic oil production failed to offset an eight percent drop in light and medium supply.

Lower production resulted in reduced deliveries of Alberta crude to both domestic and export markets. Domestic deliveries fell by 2.3 thousand cubic metres (14.5 thousand barrels) per day, while exports to the United States and offshore markets dropped by 5.5 thousand cubic metres (34.6 thousand barrels) per day (Figure 2).

Shipments to the United States Midwest, the traditional export market for Canadian crude, declined by 6.2 thousand cubic metres (39 thousand barrels) per day. As a result, the Canadian share of Midwest imports fell to 45 percent, from approximately 55 percent in each of the previous two years. Exports to other regions increased by seven percent overall, thereby contributing to a greater diversification of market outlets for Alberta crude.

Aided by continuing strong economic growth, domestic refinery runs increased by three percent to 258 thousand cubic metres (1.6 million barrels) per day. This growth was not evenly distributed across the provinces as refiners in Ontario and the Prairies increased runs by seven and six percent respectively, while those in Quebec and British Columbia reduced runs by four and two percent. The widening gap between increasing requirements and decreasing domestic supply

FIGURE 1
ALBERTA CRUDE OIL PRODUCTION
THOUSAND CUBIC METRES PER DAY

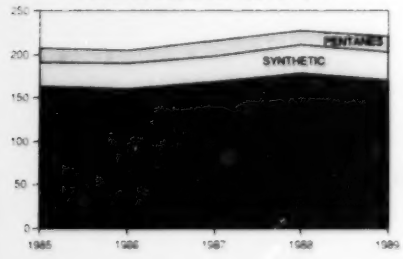
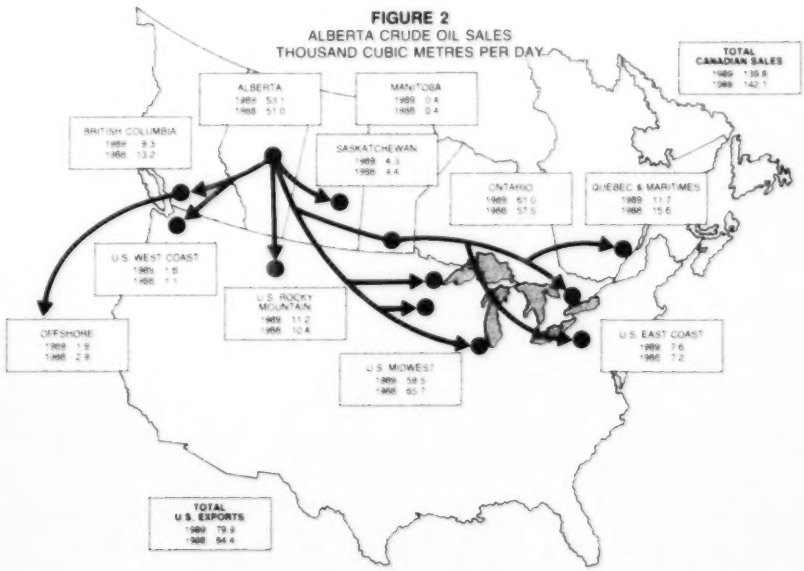


FIGURE 2
ALBERTA CRUDE OIL SALES
THOUSAND CUBIC METRES PER DAY



was filled by imports, mainly from the North Sea and West Africa. Total imports increased by seven percent during 1989 to reach 77 thousand cubic metres (485 thousand barrels) per day. The overall demand for products grew by six percent for the year, with heavy fuel oil demand gaining over 18 percent. Demand for distillate and gasoline grew modestly. Since product demand outpaced refinery runs, domestic needs had to be met by reducing exports and increasing imports.

Overall, 1989 was a positive year for the Canadian oil industry because of higher crude oil prices and improved product demand. The industry also welcomed reduced United States import tariffs which are being phased out gradually under Free Trade Agreement provisions, and elimination of the 3.5 cent per barrel Superfund Tax differential on United States imports. The benefits of these positive developments were offset by declining conventional light and medium crude production in Alberta and a stronger Canadian dollar. Uncertain oil prices caused deferrals or cancellations of several non-conventional crude oil projects.

NATURAL GAS MARKETS

United States

During 1989, United States gas demand increased by three percent to 526 billion cubic metres (18.7 trillion cubic feet), the third consecutive year of growth. Most of this growth occurred in December because of extremely cold temperatures in both the Northeast and Midwest markets. This surge in demand pushed pipeline and storage delivery capabilities to their peaks.

Strong economic growth and resulting industrial gas demand also strengthened gas consumption during the year. Increased demand by power plants and more competitive gas prices relative to other fuels, particularly fuel oil, also increased gas sales.

Pipeline transportation availability and periodic supply constraints continued to influence prices, particularly in the spot gas market which relies mainly on short-term interruptible transportation arrangements. Average spot prices for 1989 were marginally lower than in 1988. However, prices increased substantially during the last quarter of the year, with Gulf Coast spot prices increasing by more than 50 percent from October to January 1990. High demand, volatile spot prices and a growing perception of a shrinking deliverability surplus are expected to sustain the trends towards rising prices and longer-term contracting.

Canadian Export Performance

Canadian exports to the United States during 1989 increased by five percent over the previous year to 37.9 billion cubic metres (1.3 trillion cubic feet). Canada's share of the United States gas market increased to approximately seven percent due to aggressive marketing of spot gas and competitive, flexible pricing of long-term contracts.

Despite a slight increase in volumes during 1989, Alberta's share of Canadian exports (Figure 3) decreased by two percent to 88 percent, or 33.2 billion cubic metres (1.2 trillion cubic feet). This decline in share reflected increased sales of British Columbia gas into the Pacific Northwest. Average export prices were marginally higher during the year. In conjunction with the slight growth in volumes, total export revenues increased by more than six percent to US$2.6 billion.

FIGURE 3
EXPORT NATURAL GAS MARKET

1988 TOTAL EXPORTS 1989
35.9 BILLION CUBIC METRES
37.9 BILLION CUBIC METRES

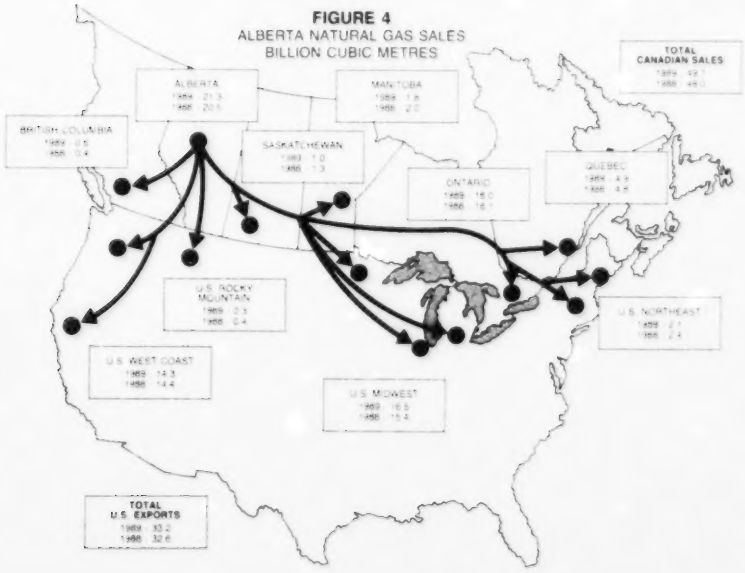
The Midwest was the major growth market for Canadian gas in 1989 (Figure 4) due to better access to pipelines serving that region and increased spot sales. In contrast, sales to all other regions decreased slightly. Despite these declines, the resurgence of demand in the United States offers the best prospect for increased Canadian sales. Proposals to serve new markets in the Northeast are well underway and plans for new and expanded pipelines into California and the Midwest have also been initiated.

One of the most significant developments affecting new United States markets for Canadian gas concerned the Northeast. Canadian producers have approved new export sales to this region via the proposed Iroquois pipeline project. Application for a major expansion of the TransCanada system has been filed to accommodate the new exports as well as the additional domestic sales that have been requested. This project will be reviewed by the National Energy Board during 1990.

A number of new pipeline projects have been proposed to serve the California market. Traditionally, Alberta has been a reliable and high-quality supplier to this market because of long-term contracts underpinned by relatively abundant proven reserves. While it is hoped that this good relationship will continue, regulatory proposals late in the year by the California Public Utilities Commission (CPUC) have created some uncertainty regarding the future attractiveness of this market for Alberta producers. Regardless of the outcome of these developments, it is expected California will remain a major market for Canadian gas, as substantiated in a CPUC decision which identified an incremental requirement of 2.1 billion cubic feet per day by 2005.

Another major issue in 1989 regarding gas exports concerned Pan-Alberta Gas' resolution of its long-standing contractual difficulties with United Gas Pipeline Company. After many months of negotiation, Pan-Alberta's United States subsidiary, NatGas U.S. Inc., acquired United's gas purchase and transportation obligations totalling 450 million cubic feet per day. The commitment from United comprised ten percent of total Canadian exports to the United States. The eventual settlement modified existing service arrangements, allowing NatGas to assume United's obligations to purchase gas supplied by Pan-Alberta through Northwest Alaskan Pipeline Company. The settlement eliminated much uncertainty in Alberta's natural gas industry as well as providing substantial long-term marketing opportunities for Pan-Alberta.

FIGURE 4
ALBERTA NATURAL GAS SALES
BILLION CUBIC METRES



Canada

Overall demand for natural gas in Canada increased by seven percent in 1989, reaching 56.5 billion cubic metres (2.0 trillion cubic feet). Most of this increase was in Alberta and British Columbia where strong economic growth in both provinces and use of natural gas for power generation in British Columbia led to demand growth of 2.3 billion cubic metres (83 billion cubic feet). Demand in Ontario and Quebec increased by 1.4 billion cubic metres (50 billion cubic feet), influenced by colder-than-normal weather.

Total 1989 sales of Alberta natural gas increased 1.4 percent to 82.9 billion cubic metres (2.9 trillion cubic feet). The intra-Alberta market grew the most, while the ex-Alberta and export markets increased only marginally. Growth in export sales was significantly limited by pipeline capacity constraints.

Revenues from intra-Alberta natural gas sales rose by five percent during 1989 as a result of increased volumes and slightly increased prices. Consumption in the residential and industrial/electrical generation sectors improved due to stronger economic growth.

Alberta's share of the interprovincial market declined from 78 percent in 1988 to 73 percent in 1989 (Figure 5), in conjunction with fairly constant sales volumes. Ex-Alberta sales reached 28.4 billion cubic metres (1.0 trillion cubic feet) during the year. Sales declines in Manitoba, Ontario and Saskatchewan were partially offset by higher sales in Quebec and British Columbia. Continued excess supply and increased gas-on-gas competition from Saskatchewan and United States imports caused prices and revenues in the ex-Alberta domestic market to decline by 8 percent overall.

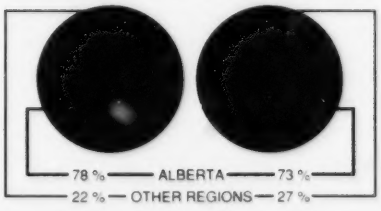
During 1989, market forces continued to shape the domestic interprovincial market. The advent of deregulation in 1985 attracted many large end-users and central Canadian local distribution companies to short-term gas purchase arrangements with independent producers, with the focus mainly on obtaining low-priced gas. Over time, however, the value of more secure traditional contracts has been enhanced, as witnessed by recent longer-term arrangements, particularly for direct sales. In 1989, natural gas sold through direct sales accounted for 30 percent of Alberta's interprovincial sales (Figure 6).

Expectations for 1990

The outlook for the Canadian natural gas industry in 1990 and beyond is positive, although pipeline expansions are required in order for exports to increase. The rising demand for Canadian gas into the United States Northeast, as reflected in the upcoming TransCanada facilities expansion, is being increasingly viewed as an attractive potential alternative to the competitive California market.

In the domestic market, sales volumes are anticipated to increase solely because of economic growth. Alberta's additional share of this growing market is expected to be inhibited by continuing inroads by other domestic gas suppliers and imports.

FIGURE 5
EX ALBERTA DOMESTIC NATURAL GAS MARKET



1988 TOTAL EX-ALBERTA 1989
36.4 BILLION CUBIC METRES — 39.1 BILLION CUBIC METRES

FIGURE 6
ALBERTA INTERPROVINCIAL NATURAL GAS SALES

1988 28.5 BILLION CUBIC METRES — **1989** 28.4 BILLION CUBIC METRES

CRUDE OIL

OVERVIEW OF OPERATIONS

The APMC, as agent for the Crown, is responsible for gathering and marketing crude oil taken as royalty-in-kind from Crown leases in the Province. It markets the Province's equity share of synthetic oil from the Syncrude Canada Ltd. project, and offers contract marketing services to Alberta producers.

As the largest volume seller of crude oil in Canada, the APMC manages a diversified sales portfolio, supplying crude to a wide base of refiners throughout Canada and the United States. It also maintains a high profile within Alberta, gathering crude oil at more than one thousand receipt points for feeder pipeline transport to central locations and local refineries or injection into extra-provincial pipeline systems.

The APMC draws from its direct involvement in the marketing and transportation of crude oil to keep the Alberta Government advised of ongoing developments and market trends. It also participates on several industry task forces and committees to promote an efficient operating environment, beneficial to the long term interests of producers and refiners of Alberta crude oil.

SALES

North American oil supply further tightened in 1989 as indigenous supplies declined and United States petroleum imports as a percentage of total requirements crossed the 50 percent threshold. Increased reliance on foreign imports had a significant impact on Mid-Continent refinery operations. During the height of the gasoline season, a supply shortfall developed as pipelines delivering imported crude from the Gulf Coast to the Mid-Continent became capacity constrained. As shown in Figure 7, increased competition for declining Lower 48 production resulted in significant price premiums for West Texas Intermediate (WTI) vis-a-vis internationally traded crudes. During 1989, monthly average futures prices for WTI crude oil rose steadily from a February low of US$17.82 per barrel to a high of US$21.09 in December (Figure 8).

Due to declining Alberta production, ex-Alberta pipeline capacity was adequate in 1989; however, pipeline-related issues continued to receive considerable industry attention.

In an effort to improve service, Interprovincial Pipe Line Company converted to a batch mode of operation. This system places the onus on shippers to provide rateable deliveries to Interprovincial, monitor their batches in transit, and make adjustments if landing schedules do not meet refinery requirements. Although the process has increased the workload of shippers, industry commentary suggests that the batch system has improved service to the shippers.

In May, Interprovincial announced that it was embarking on an 18 month corrosion testing program. The testing program has not had a major impact on pipeline operations and results indicate future deliveries should not be significantly affected by whatever maintenance may be required. In the fourth quarter, after much debate, plans for a major expansion of the InterProvincial system were shelved due to reduced production expectations. Plans for an expansion to the Trans Mountain system were also deferred.

As a major shipper of crude oil, the APMC has developed expertise in facilitating crude oil movements and has established a reputation as a reliable supplier of Alberta crude.

Figure 9 summarizes the total provincial production of conventional crude oil and the royalty share which is marketed by the APMC. Receipts of light and medium royalty oil totalled 7.6 million cubic metres (47.7 million barrels), down six percent from

FIGURE 7
1989 PRICE PREMIUMS WTI vs. OPEC BASKET
U.S. DOLLARS PER BARREL

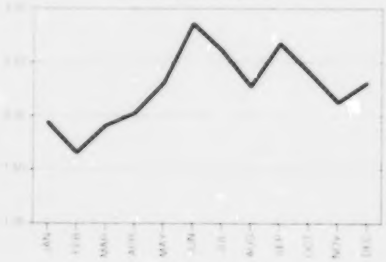
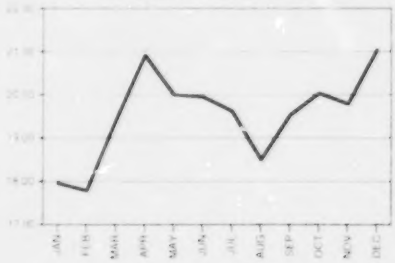


FIGURE 8
NEW YORK MERCANTILE EXCHANGE
1989 WTI SPOT MONTH SETTLEMENT PRICES
U.S. DOLLARS PER BARREL



1988. Royalty receipts of heavy crude were 856 thousand cubic metres (5.4 million barrels), down almost five percent from 1988. Total revenue from royalty sales of conventional crude oil production was $1.1 billion, up ten percent from the previous year.

PRICING

By international standards, Alberta production achieved premium prices in 1989 due to lower production levels in the United States Mid-Continent and healthy United States demand. These factors were transmitted to Canadian producers through the direct link between Canadian and United States crude oil prices.

Table 1 shows monthly reference prices for sweet and sour crude paid by the APMC for field purchases during 1989. APMC reference prices are based on sales revenue net of transportation costs from Edmonton to final point of sale. During the year shipping costs rose due to higher tariffs on the Interprovincial and Trans Mountain pipeline systems.

Appreciation of the Canadian dollar also had an adverse impact on 1989 crude prices and on sales netbacks.

Quality adjustments and pipeline tariffs are deducted from APMC reference prices to determine field prices for more than six thousand producing battery locations.

In response to revised industry standards, the APMC implemented new quality adjustment factors for density and sulphur. It also worked to reach agreement on light ends and sulphur quality adjustment factors for condensate streams.

TABLE 1
1989
CRUDE OIL REFERENCE PRICES
(DOLLARS PER CUBIC METRE)

	SWEET CRUDE	SOUR CRUDE
JAN	123.81	119.82
FEB	125.44	121.45
MAR	132.17	129.66
APR	144.22	142.23
MAY	147.23	145.49
JUN	144.61	143.01
JUL	144.64	143.24
AUG	135.18	133.74
SEP	136.87	135.28
OCT	140.66	139.13
NOV	141.49	139.85
DEC	144.34	141.09
AVG.	138.39	136.17

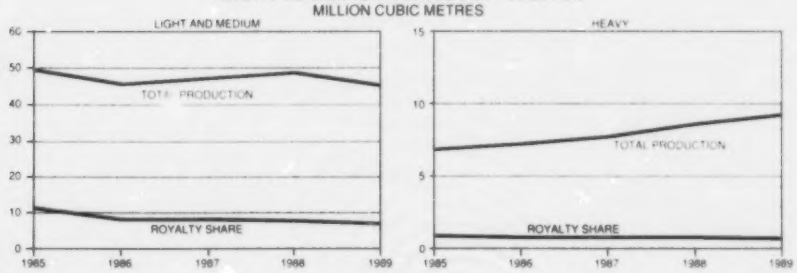
Prices shown are for crude oil with a density of 825 kilograms per cubic metre and a sulphur content of not more than 5 grams per kilogram delivered into, respectively, sweet or sour pipelines.

SYNTHETIC CRUDE

The Province has a 16.74 percent equity participation in the Syncrude Canada project and receives a 50 percent share of the project's deemed net profits in lieu of royalty.

Total Syncrude production dropped one percent in 1989 to 8.6 million cubic metres (54.0 million barrels). Although a major capacity expansion was completed during the third quarter of 1988, annual production in 1989 was adversely affected by two unscheduled coker turnarounds. In addition, December output was only 65 percent of expected levels due to a fire in a gas-oil hydrotreater. The volume of syncrude received by the APMC during 1989 for subsequent sale was 1.4 million cubic metres (9.0 million barrels), down two percent from the previous year.

FIGURE 9
ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION
MILLION CUBIC METRES



NATURAL GAS

OVERVIEW OF OPERATIONS

Since the deregulation of natural gas prices on November 1, 1986, APMC activities have included:

Natural Gas Marketing Act (NGMA)

- at the request of producers and purchasers, the determination of costs, charges and revenues representing components of the price of natural gas;
- the issuance of findings of producer support for netback pricing arrangements;
- the collection and analysis of information on Alberta natural gas prices and markets.

Take-or-pay Costs Sharing Act

- the determination of take-or-pay levies and payment of take-or-pay costs.

NATURAL GAS MARKETING ACT

Services Relating to Price Components

Under the authority of Part 1 of the NGMA, the APMC may agree to provide the following services under a gas contract:

- the determination, confirmation, or verification of price components;
- the allocation of all or part of the amount of a price component to a gas contract or contracts;
- the redetermination of price components or the calculation of adjustments of price components;
- any other services that pertain to or are incidental to the ascertainment of the amounts of price components.

During 1989, the APMC provided price component services to three clients on a cost recovery basis.

Producer Support for Downstream Pricing

Part 2 of the NGMA provides for producer input to the resale price if producers and buyers have agreed to a netback pricing clause in their natural gas purchase contract. NGMA regulations require the buyer to obtain support from a minimum number of producers by number and by volume of supply.

As a result of a review initiated by the APMC and after considering the views of producers and shippers, the minimum requirement by volume was reduced from 70 percent to 60 percent as of December 15, 1989. The criteria by number of producers remains unchanged at 51 percent.

Procedurally, a buyer presents a resale proposal to the producers for voting purposes and the results of the vote are provided to the APMC. A finding of producer support is issued if the legislated criteria are met. Shippers of netback gas may be subject to penalties imposed by the APMC if gas is shipped without a finding of producer support. During 1989, the APMC issued 37 decisions in respect of producer support.

Information Collection

The APMC collects information relevant to the purchase and sale of marketable Alberta natural gas under Part 4 of the NGMA. The data collected include field purchase information provided primarily by first buyers, while figures relevant to consumption within Alberta are supplied by large volume end-users and designated distributors. Ex-Alberta sales information is provided by the owners of the natural gas at the time it leaves Alberta. Owners similarly provide information pertinent to imports of natural gas into Alberta.

Information is collected on a confidential basis for use in developing government policies, verifying royalty payments, and establishing average market prices for determining the royalty share of natural gas production. The statistics are also used to monitor progress under the October 31, 1985 Agreement on Natural Gas Markets and Prices.

TAKE-OR-PAY COSTS SHARING ACT

The National Energy Board (NEB), under the terms of the October, 1985 Agreement, was requested to review the availability of transportation service on the TransCanada PipeLines Limited system, taking into account the equitable sharing of take-or-pay charges. In its May, 1986 report, the NEB recommended that take-or-pay costs be shared by Alberta non-system gas transported on the TransCanada system, and that the arrangements be administered by the Government of Alberta.

In response, the Government of Alberta enacted the Take-or-pay Costs Sharing Act which became effective November 1, 1986. This Act provides for the sharing of take-or-pay financing costs of Consolidated Natural Gas Limited and TransCanada by way of a monthly levy on users of the TransCanada system whose shipping arrangements were entered into after October 31, 1985. The levy on users of the system remained at ten cents per gigajoule for the period November 1, 1986 to October 31, 1989. It was reduced to seven cents per gigajoule for the period November 1, 1989 through October 31, 1990.

The APMC makes monthly determinations of levies to be applied to TransCanada producers, Consolidated producers, shippers on the Nova Corporation of Alberta system, shippers on provincial carrier systems and to provincial carriers that own the gas. The APMC also determines, on a monthly basis, the quantities of natural gas exempted from the levies.

Revenues derived from the assessment of levies are deposited in the Take-or-pay Costs Sharing Fund for subsequent payment of take-or-pay financing costs. Levies assessed against parties, excluding TransCanada and Consolidated producers, accounted for 14.5 percent of total levies during 1989.

NATURAL GAS PRICING AGREEMENT ACT

Under provisions of the Natural Gas Pricing Agreement Act, the APMC has authority to redetermine the Alberta Cost of Service for an original buyer for any month up to and including October, 1986 in order to comply with decisions of the Alberta Public Utilities Board. During 1989, one such decision regarding APMC determinations of Alberta Cost of Service was outstanding as a result of an appeal to the Alberta Court of Appeal.

The final distribution of $14.6 million from the Natural Gas Pricing Agreement Act Fund to producers and buyers of record for October 1986 deliveries was made in January, 1989. This refund amounted to 6.83 cents per gigajoule.

REGULATORY AFFAIRS

The APMC participates in the regulatory process in both Canada and the United States, presenting the Province's views on matters affecting the marketing of Alberta's crude oil and natural gas resources. Regulatory activities were focused on the proceedings of the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), and the California Public Utilities Commission (CPUC).

CANADA

Early in 1989, the APMC participated in a proceeding to deal with an application by TransCanada PipeLines Limited for authorization to build additional facilities for the 1990/1991 contract year. The $710 million expansion was designed to provide 520 million cubic feet per day of additional capacity, of which 70 million cubic feet were for domestic use and 450 million cubic feet for new export sales. The NEB ultimately approved facility costs of $593 million to provide 469.5 million cubic feet per day of additional capacity. An associated United States expansion of the Great Lakes Gas Transmission Company system has not yet been approved by the FERC. Major issues in the TransCanada hearing were the incremental economic value of the proposed project and the appropriate method for evaluating pipeline expansions. While the APMC supported the need for pipeline expansions to be evaluated on an incremental basis to ensure that such projects were economically sound, it did not support the introduction of any specific test.

The NEB also heard, as part of the TransCanada facilities proceedings, the export proposals underlying the forecast throughput. Of these applications, four were denied for reasons including that the export did not provide a net social benefit to Canada. Three of the denied licence applicants appealed the decision to the Federal Court of Canada. At issue is the use of benefit cost analysis by the NEB in its review of export licence applications.

Mid-year, TransCanada filed an application for approval of new tolls for the 1990 test year. TransCanada sought approval of a 32.5 percent equity component in its capital structure, a 14.5 percent return on equity and a $1 billion revenue requirement. It did not propose any tariff or toll design changes. The APMC intervened and supported the Canadian Petroleum Association (CPA) evidence on rate of return matters and addressed the policies and procedures TransCanada would use for expenses, relative to their head office relocation.

In an attempt to clarify the procedure and improve its usefulness, the NEB proposed to amend the filing requirements for an export impact assessment. The APMC filed comments on the proposed changes, emphasizing that the assessment should not be structured or used so as to inhibit the market's operation or to interfere with the market's ability to determine where gas should be sold. The APMC contended that the role of export impact assessment should be limited to being used to identify market failure. The NEB decided to continue to evaluate export impact assessment as part of the market based procedure, but not on a project specific basis; rather, the NEB would prepare an assessment for a variety of aggregate levels of projected exports. Applicants then could rely on these estimates to support their projects, or could prepare their own. The NEB's evaluation would address supply, demand, prices and export levels, as recommended by the APMC.

Throughout 1989, the APMC attended various export licence proceedings to monitor the implementation of the NEB's new surplus determination procedures, announced in the fall of 1987. Of particular interest was the application to export a total of 9.2 trillion cubic feet of natural gas from the Mackenzie Delta region, commencing November 1, 1996. The NEB released a decision on this matter in October, granting licences subject to conditions which would assure that potential Canadian buyers would be given an opportunity to purchase the gas under similar terms and conditions.

During the year, the Treasury Board of Canada approved the recovery of 100 percent of the NEB's operating costs from companies it regulates on a broad commodity allocation basis, and directed the NEB to submit a proposed cost recovery mechanism. The NEB's proposal, which required full cost recovery from industry, was opposed by the APMC. Instead, the APMC suggested that a consultative committee be struck to review the allocation of costs on a detailed functional basis. Final implementation of the cost recovery mechanism is expected in June 1990.

Late in 1989, the NEB called for written submissions to review certain aspects of the market-based surplus determination procedure and, in particular, the use of its benefit cost analysis in determining whether an export project was in the public interest. The APMC submission recommended that benefit cost analysis be eliminated from the market-based procedure as its use was inconsistent with a deregulated market. The APMC contended that through the use of benefit cost analysis, the NEB was imposing an implicit price test on gas exports, as well as interfering with the market by substituting its judgement with respect to resource costs, prices, and demand for that of the market participants. Given the large number of assumptions required, the imprecise nature of the results was also of concern.

In November, TransCanada filed a major facilities application seeking NEB approval to construct additional facilities which would provide incremental sales and transportation service for domestic and export markets for the 1991/1992 and 1992/1993 contract years. The new facilities would be installed along an all-Canadian route and would provide additional throughput capacity of approximately 962.3 million cubic feet per day at a cost of approximately $2.6 billion, of which 105.3 million cubic feet per day would move to the domestic market. Exports of 726 million cubic feet per day would be destined primarily to the United States Northeast market. The NEB has approved export licences for more than half the volumes to be exported, including the Alberta Northeast Gas Limited project volumes. Given the size of this expansion, and the fact that most of the gas will be exported, the topics to be addressed are expected to be controversial. The issues include the incremental economics of the various components of the expansion, the tolling methods, and the vulnerability and reliability of the Northeast market over the long term. The APMC will be taking an active role in the hearing which starts in March 1990.

The APMC also participated in proceedings dealing with toll design issues of crude oil pipelines. At the NEB's request, Interprovincial Pipe Line Company completed a generic toll design study in June 1988. The study proposed that an integrated surcharge be applied to the transmission component of Interprovincial's revenue requirement. This would capture the differential cost imposed by transporting hydrocarbons of heavier density and viscosity than light crude oil. Surcharges of 20 percent for heavy crude oil and eight percent for medium crude oil were derived on an optimal design basis. The APMC supported most of the elements in the Interprovincial study and also recommended the separate treatment and surcharging of special facilities costs, stressing the importance of concepts such as user pay and cost causality.

In October, Trans Mountain Pipe Line Company Ltd. filed its rate application for 1990 tolls. The APMC and other shippers reached a consensus with Trans Mountain on the issues outlined in its application, subject to a later review. The APMC opposed Trans Mountain's request that the refined products receiving lines in Edmonton be rolled into the common rate base rather than be treated as a special facility. In its decision, the NEB ordered that the receiving lines continue to be classified as special facilities.

UNITED STATES

Regulatory events in California dominated much of the focus in the United States in the last quarter of 1989. The CPUC continued its recent initiatives to restructure the California gas utility business in order to increase the service options available. This would be done by unbundling utility functions and initiating changes to ensure that California gas consumers benefited from the lowest-priced natural gas supplies possible. To further these objectives, the CPUC examined the state utilities' purchasing practices as part of a November en banc hearing to discuss natural gas procurement and system reliability issues. Prior to the hearing, the APMC filed comments with the CPUC supporting the maintenance of the core-elect portfolio, which has benefited both California consumers and Alberta producers. A draft decision on procurement was released in February 1990, recommending elimination of the core-elect portfolio.

Late in 1988, the CPUC proposed a procedure to allow California utilities and other interested parties to agree on the provision of additional pipeline capacity to serve the growing California market. During 1989, the APMC carefully monitored the evolution of this procedure and filed comments on an Administrative Law Judge decision, which recommended a Wyoming-based project over projects which would transport Canadian gas. The APMC pointed out that Alberta has been a reliable, competitively-priced supply source, and urged the CPUC to allow California utilities to make their own decisions with respect to supply choices. A few months later, the CPUC reversed the Judge's decision, allowing competitive forces to select the projects that would be built.

Pacific Gas & Electric Company's Annual Cost Allocation Proceeding was held in late November and early December. This proceeding considered a variety of policy initiatives and provided a forum to discuss issues such as the competitiveness of Pacific's core price and its existing supply arrangements with Alberta & Southern Gas Co. Ltd. The APMC attended the proceeding and later filed a brief after the conclusion, indicating flaws in a proposal put forward by a California consumer advocacy group which supported regulatory intervention to lower Pacific's gas costs and to undermine the long-standing Alberta gas supply arrangements. The APMC emphasized that the existing long-term reliable arrangements between Alberta and California have been mutually beneficial over the past three decades.

The APMC made several representations to the FERC during 1989. In a joint submission with the CPA and the Independent Petroleum Association of Canada, the APMC filed a protest and intervention to a tariff filing by Great Lakes. Specifically, the protest was based on the proposed high rate of return on common equity and the volumes of transportation service used to derive commodity rates. With respect to rate issues, the APMC urged that the modified fixed-variable rate design on the Great Lakes system be replaced by a full fixed-variable rate design. While a settlement conference in December provided a forum for interested parties to discuss the issues, many issues are still outstanding.

In conjunction with the CPA, the APMC also intervened and filed a protest in the Great Lakes Open Access Certificate proceeding before the FERC. The protest encouraged the FERC to disallow the priority afforded to overrun services proposed by Great Lakes, which, most notably, would affect TransCanada, the largest firm shipper on the Great Lakes system. The APMC suggested that the current queue for interruptible service be replaced with a lottery system to award available interruptible capacity; a settlement was reached early in 1990.

The FERC released a Policy Statement on rate design issues on May 30, 1989, which delayed some of the scheduled rate cases while parties determined potential impacts. This was the case with Northern Natural Gas Company which had filed to adjust its gas tariff in an attempt to resolve the majority of issues related to its rate case. The FERC's Policy Statement broadened the scope of Northern Natural's proceedings, offering the potential of further decreasing transportation rates for shippers on its system. The APMC and the CPA supported Northern Natural's proposal to establish lower transportation rates and achieve rate stability, while providing for a fair and reasonable resolution of the postage-stamp versus mileage-rate issue.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1989 and the statement of revenue and expenditure for the Operating Fund and the statement of operations for the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1989 and the results of its operations and the changes in its financial position for the year then ended in accordance with the disclosed basis of accounting, as described in Note 2 to the financial statements, applied on a basis consistent with that of the preceding year.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 26, 1990

BALANCE SHEET

At December 31,	1989	1988
ASSETS		
OPERATING FUND		
Current		
Cash	$ 5,347,675	$ 5,336,137
Accounts receivable	368,814	432,346
Prepaid expense	6,348	32,560
	5,722,837	5,801,043
Furniture, equipment and leasehold improvements, at cost *(Note 3)*	3,029,616	3,481,380
	8,752,453	9,282,423
PETROLEUM MARKETING FUND		
Current		
Cash	23,543,660	9,249,829
Accounts receivable	148,123,140	118,850,444
	171,666,800	128,100,273
	$ 180,419,253	$ 137,382,696
LIABILITIES		
OPERATING FUND		
Current		
Accounts payable	$ 227,944	$ 157,776
Payable to the Province of Alberta	3,692,393	3,896,792
Deferred contributions	1,802,500	1,746,475
	5,722,837	5,801,043
Equity in fixed assets	3,029,616	3,481,380
	8,752,453	9,282,423
PETROLEUM MARKETING FUND		
Current		
Accounts payable	70,965,757	50,294,408
Crown royalty payable	100,701,043	77,805,865
	171,666,800	128,100,273
	$ 180,419,253	$ 137,382,696

The accompanying notes are part of these financial statements.

STATEMENT OF REVENUE AND EXPENDITURE - OPERATING FUND

Year Ended December 31,	1989	1988
Revenue		
Crude oil marketing fees	$ 2,973,494	$ 3,331,062
Interest	1,602,615	1,469,072
Natural gas price component service fees	278,250	165,544
	4,854,359	4,965,678
Expenditure		
Salaries and employee benefits	4,868,680	4,598,784
Rental and maintenance of premises *(Note 6)*	1,040,370	1,022,314
Furniture and equipment	373,744	49,743
Hearing costs *(Note 4)*	260,494	237,574
Travel, hospitality and conferences	193,765	169,901
Maintenance of equipment	124,421	141,787
Rental of equipment	108,497	98,876
Consulting services	102,922	118,272
Printing and office supplies	101,218	98,520
Computer software	85,342	56,757
External computer services	69,673	59,974
Telephone	37,740	38,046
Publications and periodicals	31,935	31,826
Postage and freight	30,000	27,506
Personnel services and recruitment	26,680	24,281
Legal	20,711	145,369
Bank charges	13,717	13,822
Leasehold improvements	10,648	-
Insurance	6,866	8,315
Miscellaneous	8,590	7,976
	7,516,013	6,949,643
Excess of expenditure over revenue	2,661,654	1,983,965
Contributions from the Province of Alberta	2,661,654	1,983,965
	$ -	$ -

STATEMENT OF OPERATIONS - PETROLEUM MARKETING FUND

Year Ended December 31,	1989	1988
Revenue from sale of crude oil	$ 1,771,615,517	$ 1,635,142,414
Less:		
Contract and other purchases	419,372,259	403,933,831
Transportation	93,496,749	100,128,316
	512,869,008	504,062,147
Net revenue to the Province of Alberta *(Note 5)*	$ 1,238,746,509	$ 1,131,080,267

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1989

NOTE 1 AUTHORITY

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980, as amended, and the Natural Gas Marketing Act, Chapter N-2.8, Statutes of Alberta 1986, as amended.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

General

These financial statements have been prepared in accordance with generally accepted accounting principles except that purchases of furniture, equipment and leasehold improvements are charged to operating fund expenditure, net of disposal proceeds, in the year of acquisition. The balance sheet, however, states the cumulative amount of such expenditures in respect of all fixed assets presently owned with the offsetting credit to equity in fixed assets.

Deferred Contributions

Contributions received from the Province of Alberta to cover operating costs for the three month period subsequent to the fiscal year end have been deferred. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure

The Natural Gas Pricing Agreement Act Fund was administered by the Commission pursuant to the Natural Gas Pricing Agreement Act. The Take-or-pay Costs Sharing Fund is administered pursuant to the Take-or-pay Costs Sharing Act. The expenditure related to the administration of these Funds is reflected in the Statement of Revenue and Expenditure - Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

NOTE 3 FURNITURE, EQUIPMENT AND LEASEHOLD IMPROVEMENTS

Changes in furniture, equipment and leasehold improvements were as follows:

	Balance December 31, 1988	Additions	Disposals	Balance December 31, 1989
Furniture and equipment	$ 2,649,561	$ 420,276	$ 882,688	$ 2,187,149
Leasehold improvements	831,819	10,648	-	842,467
	$ 3,481,380	$ 430,924	$ 882,688	$ 3,029,616

NOTE 4 HEARING COSTS

Hearing costs are comprised of the following:

	1989	1988
Outside counsel and consultants	$ 161,644	$ 133,781
Travel	56,430	75,922
Transcripts	42,420	27,871
	$ 260,494	$ 237,574

NOTE 5 PETROLEUM MARKETING FUND - NET REVENUE

Net revenue to the Province of Alberta consists of:

	1989	1988
Conventional oil - royalty share	$ 1,060,942,404	$ 962,197,117
Synthetic oil - royalty & equity share	197,804,105	168,883,150
	$ 1,258,746,509	$ 1,131,080,267

NOTE 6 COMMITMENT

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360 plus other occupancy costs.

NOTE 7 COMPARATIVE FIGURES

The 1988 figures have been reclassified where necessary to conform to the 1989 presentation.

NOTE 8 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Take-or-pay Costs Sharing Fund as at December 31, 1989 and the statement of revenue and expenditure for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1989 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 26, 1990

TAKE OR PAY COSTS SHARING FUND

BALANCE SHEET

At December 31,	1989	1988
ASSETS		
Current		
Cash	**$ 2,042,157**	$ 1,824,825
Accounts receivable	**14,971,550**	16,874,152
	$ 17,013,707	$ 18,698,977
LIABILITIES		
Current		
Accounts payable	**$ 5,750,226**	$ 6,485,440
Deferred revenue *(Note 3)*	**11,263,481**	12,213,537
	$ 17,013,707	$ 18,698,977

STATEMENT OF REVENUE AND EXPENDITURE

Year ended December 31,	1989	1988
Revenue		
Take-or-pay levies	**$ 184,615,761**	$ 187,532,735
Interest	**266,755**	170,394
	184,882,516	187,703,129
Expenditure		
Take-or-pay costs	**184,882,516**	187,703,129
Excess of revenue over expenditure	**$ -**	$ -

The accompanying notes are part of these financial statements.

TAKE OR PAY COSTS SHARING FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1989

NOTE 1 AUTHORITY

The Take-or-pay Costs Sharing Fund was established by the Take-or-pay Costs Sharing Act, Chapter T- 0.1, Statutes of Alberta 1986, as amended.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Administration Costs

In accordance with the Take-or-pay Costs Sharing Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure - Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

NOTE 3 DEFERRED REVENUE

Deferred revenue represents the portion of December levies which will be used to pay future take-or-pay costs.

NOTE 4 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1989 and the statement of revenue, expenditure and fund balance for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1989 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 26, 1990

NATURAL GAS PRICING AGREEMENT ACT FUND

BALANCE SHEET

At December 31,	1989	1988
ASSETS		
Current		
Cash	$ -	$ 18,094,784
Accrued interest	-	57,816
	$ -	$ 18,152,600
FUND BALANCE		
Fund balance	$ -	$ 18,152,600

STATEMENT OF REVENUE, EXPENDITURE AND FUND BALANCE

Year Ended December 31,	1989	1988
Revenue		
Interest	$ 144,088	$ 1,186,207
Expenditure		
Price adjustments *(Note 3)*	14,646,713	(3,133,141)
Excess (deficiency) of revenue over expenditure	(14,502,625)	4,319,348
Fund balance, beginning of year	18,152,600	11,368,858
	3,649,975	15,688,206
Transfer to General Revenue Fund *(Note 4)*	(3,649,975)	-
Transfer from Natural Gas Pricing Agreement Market Development Fund	-	2,464,394
Fund balance, end of year	$ -	$ 18,152,600

The accompanying notes are part of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1989

NOTE 1 AUTHORITY

The Natural Gas Pricing Agreement Act Fund was established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Pursuant to the Western Accord and the Agreement on Natural Gas Markets and Prices of October 1985, the Commission ceased the purchasing and selling of natural gas and the distribution of export differential with respect to gas delivered after October 31, 1986.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund was administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure - Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

NOTE 3 PRICE ADJUSTMENTS

The final distribution of price adjustments was based on October 1986 deliveries. The 1988 comparative figure represents an adjustment resulting from the settlement of an outstanding claim relating to prior delivery periods.

NOTE 4 TRANSFER TO GENERAL REVENUE FUND

In accordance with the Natural Gas Pricing Agreement Act, and as directed by the Minister of Energy, the Fund balance was transferred to the Province of Alberta General Revenue Fund.

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

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